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Revised Gas-Oil Ratio Criteria Key Indicators Of Reservoir Fluid Type

Part 5: The previous four articles in this series revealed the differences and similarities among the five reservoir fluids in detail.[1-4] This concluding article discusses guidelines for using field data to determine the fluid type, the laboratory evidence that verifies fluid type and the production behavior of the five fluids.

Table 1 gives the guidelines for determining fluid type from field data. Three properties are readily available: the initial producing gas-oil ratio (GOR), the gravity of the stock-tank liquid and the color of the stock-tank liquid.[1] Initial producing GOR is by far the most important of the indicators and should be considered first, with the other two indicators used to confirm fluid type. Stock-tank liquid gravity and color are both indicators of the quantity of heavy components present in the initial reservoir fluid. Darker colors are associated with the largest, heaviest molecules in the petroleum mixture.

If any one of these three properties fails to meet the criteria of Table 1, the test fails and a representative sample of the reservoir fluid must be examined in a laboratory to establish fluid type.

The initial producing GOR guidelines given in Table 1 are somewhat different than rules presented by other authors. The rationales for selection of the values in Table 1 are given in the previous articles in this series.[2-4] These articles are the first to present empirical evidence to support the selection of GOR criteria for identifying fluid type.

Table 2 shows the expected laboratory analysis results of the five fluids. The oils will exhibit bubble points, the retrograde gases will display dew points, and the other gases will demonstrate no phase change throughout the pressure range expected in the reservoir. The heptanes plus composition cutoff between black oils and volatile oils (20 mole %) is not exact. Values from 19 to 22 mole % might be observed.[2] However, the cutoff of 12.5 mole % between volatile oils and retrograde gases is fairly sharp.[3] The compositions of 4 mole % and 0.7 mole % for the other gases are based on engineering applications. Some retrograde liquid will likely occur in the reservoir in either case.[4]

Oil formation volume factor has been defined for use in oil material balance calculations. Since these calculation procedures are not applicable to volatile oils, formation volume factor usually is not measured for volatile oils. But one laboratory result that indicates the presence of a volatile oil is an oil formation volume factor at bubble-point pressure of 2.0 res bbl/STB or greater.

Production Characteristics

Production trends for the five fluids are shown in Table 3. Producing GOR is constant for oils as long as reser-

TABLE 1. FIELD INDENTIFICATION OF RESERVOIR FLUIDS

	Black oil	Volatile oil	Retrograde oil	Wet gas	Dry gas
Initial producing gas-liquid ratio, scf/STB	<1,750	1,750 to 3,200	>3,200	>15,000*	100,000
Initial stock-tank liquid gravity, °API	<45	>40	>40	Up to 70	No liquid
Color of stock-tank liquid	Dark	Colored	Lightly colored	Water white	No liquid

* For engineering purposes.

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TABLE 2. LABORATORY ANALYSIS

	Black oil	Volatile oil	Retrograde gas	Wet gas	Dry gas
Phase change in reservoir	Bubble point	Bubble point	Dew point	No phase change	No phase change
Heptanes plus, mole %	>20%	20 to 12.5	<12.5	<4*	<0.7*
Oil formation volume factor at bubble point	<2.0	<2.0	—	—	—

* For engineering purposes

voir pressure is above bubble-point pressure. Both oils exhibit increasing producing GORs when two phases exist in the reservoir. This increase is due to the existence of reservoir gas which has much lower viscosity and, therefore, moves more easily than the oil to the well bore. Of course, as reservoir pressure declines further, the amount of gas in the reservoir increases. This causes an increase in the effective permeability to gas and a decrease in the effective permeability to oil. As a result, the ratio of gas to oil in the reservoir flow stream increases.

Gases

Dry gases associated with black oils leave the flow stream in the first stage of separation. The retrograde gases associated with volatile oils release some condensate in the first stage of separation. Therefore, black oils typically have higher surface GORs than volatile oils during most of the producing time.[2] Notice the decrease in producing GORs for both oils late at the end of the production period in Table 3. This turndown is primarily due to the severe increase in gas formation volume factor at low reservoir pressures.

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Retrograde gases also demonstrate constant producing GORs early when the pressure is above the dew-point pressure of the gas. And retrograde gases have increasing producing GORs at pressures below the dew point. However, the reason for this increase is different than for the oils. Very little of the liquid released from retrograde gases in the reservoir will flow. This is liquid which would be a part of the condensate at the surface were it not lost in the reservoir. Thus the condensate yield at the surface decreases and the GOR increases as reservoir pressure declines during production.

The producing GOR of a true wet gas remains constant throughout the life of the reservoir as shown in Table 3. Remember, though, that guidelines for identifying a wet gas for engineering purposes cut fairly deep into the range of fluids that exhibits some retrograde behavior. Therefore, an increase in GOR later in the production period of a wet gas might be expected.

Liquids

The changes in API gravity of the stock-tank liquids during production, as shown in Table 3, are interesting. These changes are often helpful in differentiating between black oils and volatile oils. Stock-tank gravity remains constant when the reservoir pressure is above the bubble-point pressure of the oil. However, as pressure falls below the bubble point, the trends are different for black oils and volatile oils.

The increasing proportions of dry gas produced with black oils as reservoir pressure declines strip some of the lighter components from the oil. Therefore, the gravity of the stock-tank oil gradually decreases throughout most of the life of the reservoir. This decrease is not significant (usually about 2° API from start to end).

Late in the life of a black oil reservoir, the gravity of the stock-tank oil will increase. At low reservoir pressures, the gas which comes out of solution from the oil in the reservoir is rich enough (wet gas) to release condensate when it is produced. This dilutes the stock-tank liquid with condensate causing the gravity to increase.

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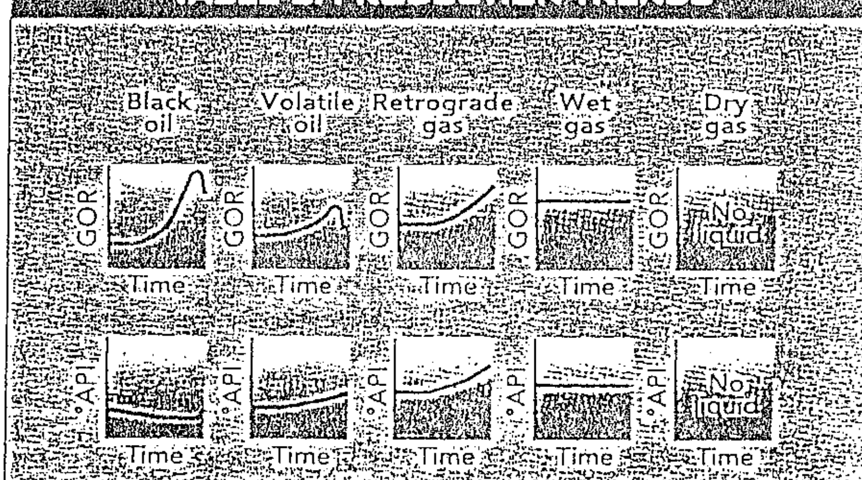
On the other hand, the increasing proportions of retrograde gas produced with volatile oils release increasing quantities of condensate at the surface. This condensate mixes with the decreasing proportions of produced oil, causing the gravity of the stock-tank liquid to increase. This change in gravity can be significant, on the order of 10 or more API units. Therefore, the trend of stock-tank oil gravities is another indicator of fluid type between black oils and volatile oils.

The gravities of the stock-tank liquids produced with retrograde

TABLE 3. PRODUCTION TRENDS



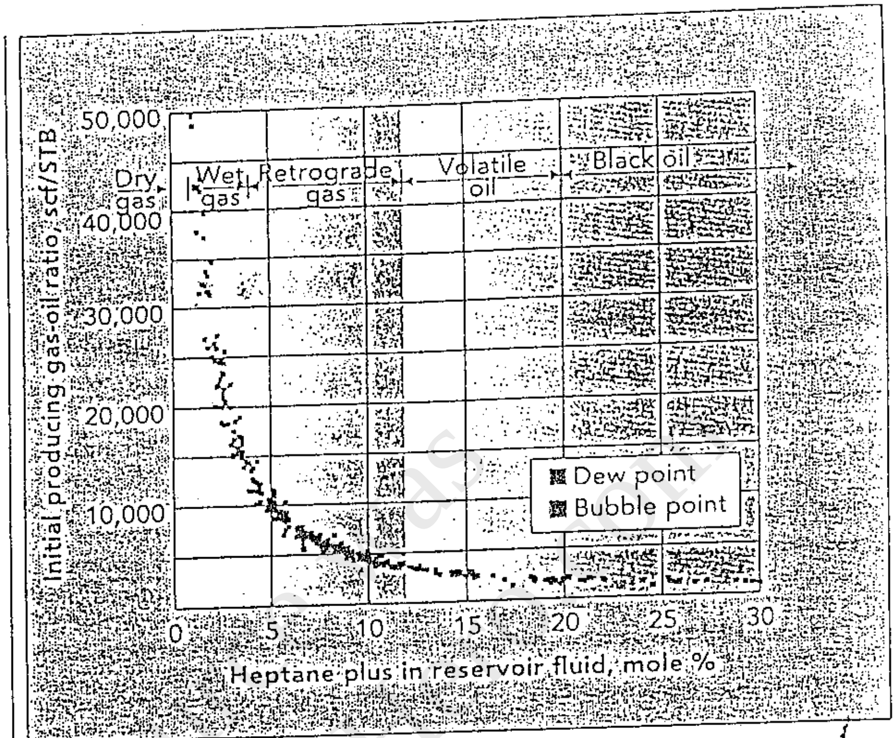


Fig. 1. The effect of composition on initial producing GOR is indicated by the composition cutoffs of the five reservoir fluids.

gases also remain constant when reservoir pressure is above the dew-point pressure of the gas and increase as reservoir pressure declines below the dew point. The trend below the dew point is a result of the heavier components of the gas being lost to the retrograde liquid in the reservoir and, therefore, not reaching the stock-tank.

Part 1 of this series presented a set of data showing the effect of composition (represented by the mole percent of heptanes plus in the fluid) on initial producing GOR.[1] Using the same data, Fig. 1 indicates the composition and initial producing cut-offs for the five fluids. The rationalizations for these cutoffs have been explained throughout this series of articles. •

References

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